APPLICATION OF

BARC ELECTRIC COOPERATIVE **CASE NO. PUE000232**

For a revision in retail base rates, service charges, and terms and conditions for electric service

REPORT OF MICHAEL D. THOMAS, HEARING EXAMINER

June 29, 2001

HISTORY OF THE CASE

On May 1, 2000, BARC Electric Cooperative (the "Cooperative") filed an Application for a general retail rate increase. The Cooperative proposed increasing its base rates, rolling present rider surcharges into its rates, revising various surcharges, adding rate schedules, and revising sections of the Terms and Conditions in its tariff.

Specifically, the Cooperative's proposed tariff revisions would increase its annual jurisdictional revenues by $815,679.00 or 7.0%. The Cooperative anticipates the requested increase would produce a Times Interest Earned Ratio ("TIER") of 2.07, using pro forma interest and a rate of return of 8.16%. The proposed rates have been designed to produce an increase in jurisdictional base revenues of $766,039.00, after the elimination of Rider Surcharges OD-11, OD-12, and OD-13. The Cooperative increased other electric revenues by $49,640.00.

The Cooperative proposed the following increases in its charges: Rural Electric Service Schedule (Residential) facilities charge from $11.00 to $12.50 per month; the Commercial and Small Power Service Schedule facilities charge from $14.00 to $17.30 per month for single-phase service, and from $14.00 to $28.00 for three-phase service. The Cooperative also revised the energy blocks for these Schedules. The Cooperative's Large Power Service Schedule LP-1 service charge would increase from $30.00 to $50.00 per month. The kW demand charge on this Schedule would be reduced from $11.00 to $10.00 per kW, and the energy blocks would also be revised.

The Cooperative also proposed an additional rate schedule, Schedule LP-2, for Large Power Service for customers with at least 1,000 kW of load taking service directly from a Cooperative-owned substation. The facilities charge for this Schedule would be $100.00 per month. The Cooperative also proposed to add Schedule SKI area service for a ski resort that has loads not in operation during wholesale billing peaks. The facilities charge for this Schedule would be $50.00 per month.

Finally, the Cooperative proposed the following increases in its fees: Collection from $15.00 to $25.00; Reconnection Normal Hours from $30.00 to $50.00; 3-Month Meter Readings from $10.00 to $20.00; Connection or Reconnection After Hours from $75.00 to $85.00; Bad Check charge from $10.00 to $20.00; Connection Fee Normal Hours from $10.00 to $20.00; Yard Light

Pole and Guy Installation from $60.00 to total cost; and Yard Light installed on existing facilities would remain at no charge.

On May 22, 2000, the Commission's Divisions of Energy Regulation, Public Utility Accounting, and Economics and Finance (collectively, the "Staff") requested that the Cooperative supplement its Application with certain detailed financial information. The Staff requested this information in order to comply with the mandate contained in § 56-582 A 3 of the Code of Virginia that the Commission, in establishing capped rates, "give due consideration, on a forward-looking basis, to the justness and reasonableness of rates to be effective for a period of time ending as late as July 1, 2007."

By Order entered on May 26, 2000, the Commission assigned the case to a hearing examiner; scheduled a hearing on the Application for November 13, 2000; established the form, manner, and the date for providing notice of the Application; and established a schedule for the parties to file additional testimony and evidence.

On June 23, 2000 and July 7, 2000, the Cooperative filed, as part of its Application, the supplemental information requested by the Staff.

The hearing was convened as scheduled on November 13, 2000. William B. McClung, Esquire, appeared as counsel for the Cooperative. The Cooperative presented the testimony of three witnesses: Hugh T. Mitchell, Jr., independent rate consultant; Jack D. Gaines, vice president and manager of the utility rate and financial services department for Southern Engineering Company; and Clyde C. Hively, Jr., assistant manager of the Cooperative. Sherry H. Bridewell, Esquire, and Katharine Austin Hart, Esquire, appeared as counsel for the Staff. The Staff presented the testimony of three witnesses: John B. Barker, public utility accountant; John R. Ballsrud, principal financial analyst; and Rosemary M. Henderson, senior utilities analyst. Rebecca W. Hartz, Esquire, appeared as counsel for the Division of Consumer Counsel, Office of the Attorney General ("Consumer Counsel").[1]

At the conclusion of the hearing the parties were afforded an opportunity to file post-hearing briefs. By agreement of counsel, briefs were to be filed simultaneously 60 days after the transcripts of the hearing were filed in the case. The transcripts were filed on January 12, 2001, and the Cooperative, the Staff, and Consumer Counsel filed their post-hearing briefs on March 12, 2001. A copy of the transcript is being filed with this Report.

No public witnesses testified at the hearing.

The Cooperative placed its proposed rates into effect on an interim basis on January 1, 2001.[2]

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[1] John F. Dudley, Esquire, subsequently replaced Ms. Hartz as counsel for the Division of Consumer Counsel, Office of the Attorney General.
[2] *See*, Letter dated December 8, 2000, D.C.C. No. 001220071.

SUMMARY OF THE EVIDENCE

Mr. Mitchell's direct testimony supported Schedule 3 (Financial & Status Statement), Schedule 8 (Capital Structure & Cost of Debt), and Schedule 9 (Rate Base) included in the Cooperative's Application. In Schedule 3, Mr. Mitchell derived an overall rate increase of 7.0%. This increase is comprised of a 6.69% increase in rates and a 24.09% increase in fees. In Schedule 8, Mr. Mitchell calculated a 5.705% blended cost of debt for the Cooperative. In Schedule 9, Mr. Mitchell calculated a Total Rate Base of $26,059,936 for the Cooperative. (Ex. HM-1, at 2-4; Schedules 3, 8 and 9).

On cross-examination, Mr. Mitchell testified the Cooperative's test year ended June 30, 1999, and its pro forma year ended June 30, 2000. Mr. Mitchell verified that the Staff essentially adopted his rate base number with two exceptions. The Staff reduced Account No. 368 (Line Transformers) by $14,385.00 and increased Account No. 399 (Other Tangible Equipment) by $2,899.00. (Tr. at 38-41; Ex. JB-7, at Appendix pg. 91).

In his prefiled rebuttal testimony, Mr. Mitchell disagreed with the Staff's adjustment to depreciation expense. The Staff has taken the position that the Cooperative used depreciation rates that were too high in several plant accounts. The Staff's adjustment to depreciation expense was ($74,060.00) versus the Cooperative's adjustment of $13,649.00. Mr. Mitchell testified the Company has been using the 10% depreciation rate for load management equipment since 1988, and this rate was used in the Company's last two rate cases, 1989 general rate case and 1992 expedited rate case. In support of his testimony, Mr. Mitchell produced a copy of the Cooperative's depreciation register from calendar years 1988, 1989, 1991, and 1992. He further produced an excerpt from Rural Utilities Service ("RUS") Bulletin 1767B-1, Uniform System of Accounts-Electric, which states that load management equipment "shall be depreciated based upon the manufacturer's estimate of the equipment's useful service life." Mr. Mitchell also produced a letter from Old Dominion Electric Cooperative dated April 5, 1988, advising its member cooperatives that it was seeking approval from REA (currently RUS) to use a 10% depreciation rate on load management equipment, and that its member cooperatives should use the 10% depreciation rate on this type of equipment. Mr. Mitchell also produced a letter from the U.S. Department of Agriculture, Program Accounting Services Division, stating that load management equipment "should be depreciated over the manufacturer's estimate of the equipment's useful life." (Ex. HM-15, at 1-2; Attachments A, B and C).

At the hearing, Mr. Mitchell's rebuttal testimony focused on the difference between the Cooperative's pro forma depreciation expense of $1,223,848.00 and the Staff's pro forma depreciation expense of $1,133,677.00. He highlighted two major differences between the parties. First, the Cooperative used a 3.07% depreciation rate for all of its distribution equipment and the Staff used a rate that was slightly more or less than 3.07% depending on the equipment account. Secondly, the Cooperative used a 10% depreciation rate on its load management equipment and the Staff used a 3.20% and a 4.40% rate depending on the equipment account. These differences account for the variance between the Cooperative's $1,223,848.00 pro forma depreciation expense and the Staff's $1,133,677.00 pro forma depreciation expense. If the Staff had used the Cooperative's depreciation rates in its Adjustment 22B, the Staff's adjustment to depreciation expense would have been a positive $7,928.00, rather than the negative $74,060.00 it recommended. Using the Cooperative's depreciation rates would result in an additional $81,988.00 in depreciation expense that the Staff should have recognized.[3] Mr. Mitchell carried the Cooperative's $1,223,848.00 depreciation expense forward to Staff Adjustment 12C and calculated a 3.30216% average depreciation rate and a rate year depreciation expense jurisdictional adjustment of $164,543.00, versus the $152,421.00 calculated by the Staff. Finally, Mr. Mitchell applied the 3.30216% average depreciation rate and the Cooperative's $1,223,848.00 depreciation expense to Staff Adjustment 11D and calculated a jurisdictional depreciation expense adjustment for the six years ending December 31, 2007, of ($24,225.00), versus ($22,440.00) calculated by the Staff. If Mr. Mitchell's adjustments are considered together, the Cooperative's revenue requirement would be $92,325.00 more than the $524,787.00 recommended by the Staff, or $617,112.00. (Tr. at 143-45, 148, 150-51; Exs. HM-16, HM-17, and HM-18).

In order to show the reasonableness of the Cooperative's 3.07% depreciation rate, Mr. Mitchell prepared an exhibit using the methodology established in RUS Bulletin 183-1 to calculate distribution plant composite depreciation rates. Mr. Mitchell calculated a lower composite depreciation rate of 2.68% and a higher composite depreciation rate of 3.31% for the Cooperative. He noted that the Cooperative's 3.07% depreciation rate is within that range. RUS guidelines require its borrowers operating under normal conditions to select a depreciation rate that is near the midpoint of the range. The Cooperative selected the 3.07% depreciation rate for distribution plant some time ago and has continued to use that rate. The Cooperative is still within its composite range when the 10% depreciation rate for load management equipment is factored in. (Tr. at 152-156; Exs. HM-19 and HM-20).

Finally, on the issue of depreciation rates for load management equipment, Mr. Mitchell testified the Staff gave the Cooperative very little notice prior to the hearing that it had to produce the manufacturer's expected life of the equipment to support the 10% depreciation rate. The Cooperative contacted a distributor of load management equipment and was advised that the company that manufactured its equipment had been bought out, the equipment the Cooperative had purchased was obsolete, and even newer versions of the same equipment were being phased out. Mr. Mitchell indicated that the Cooperative plans to replace its load management equipment in the near future. In Mr. Mitchell's opinion, the 10% depreciation rate for the load management equipment was realistic based on the fact the equipment was first placed in service in 1988. (Tr. at 156-161).

On cross-examination, Mr. Mitchell testified load management equipment is included in the general ledger accounts, 362.3 to 362.4, 370.1 and 595.1, depending on where the equipment is located. He further testified the Cooperative disclosed its depreciation rates in each of its annual audit reports to RUS, and RUS has not questioned the Cooperative on its depreciation rates. (Tr. at 174-76).

In his prefiled rebuttal testimony, Mr. Mitchell further disagreed with the Staff's proposal that all property and payroll taxes should be booked to Taxes Other than Income rather than Operations and Maintenance ("O&M") expenses. In support of the Cooperative's position, Mr.

[3] If the Staff's methodology and the Cooperative's depreciation rates are used, this produces an adjustment to depreciation expense of $8,053.00 and results in depreciation expense of $82,113.00. *See*, Adjustment to Depreciation Expense, Page 91 – H.E. Revised attached to this Report.

Mitchell produced a letter from the U.S. Department of Agriculture, Program Accounting Services Division, requiring that RUS borrowers allocate employee pensions and benefits expense, as well as payroll taxes and insurance costs, to the appropriate functional operations, maintenance, and administrative expense accounts. Mr. Mitchell also produced excerpts from RUS Bulletin 1767B-1, Uniform System of Accounts-Electric ("USOA"), which detail what should be booked in various O&M expense accounts. Mr. Mitchell stated the Cooperative would not be in compliance with the directives contained in the USOA if it did not include property taxes and payroll taxes in its O & M expense accounts. (Ex. HM-15, at 2-3: Attachments C and D).

Mr. Mitchell also disagreed with the Staff's long-term debt interest expense shown in Staff witness Ballsrud's prefiled testimony Schedule 4, page 1 of 8. Mr. Mitchell believes the Staff is not reflecting a 12-month effect to interest on long-term debt on the Cooperative's Federal Financing Bank ("FFB") notes. The Cooperative calculated 12-month interest at $129,179.00 and the Staff calculation was $89,640.00, a difference of $39,539.00. Mr. Mitchell testified that the 12-month effect on interest has been allowed in prior rate cases. (Ex. HM-15, at 3-4).

On cross-examination, Mr. Mitchell testified the Cooperative borrowed the funds covered by the FFB notes in February and June 2000. By the end of the pro forma year, June 30, 2000, the $2,072,000 the Cooperative borrowed was known and measurable. On a going-forward basis, the interest payments would have to be recognized, and Mr. Mitchell did this by calculating a 12-month interest expense on both notes. (Tr. at 177-181).

Mr. Gaines' prefiled direct testimony addressed the Cooperative's proposed rates, tariffs, and revenue allocation. He also prepared the Cooperative's fully allocated and unbundled cost of service study. In addition, Mr. Gaines developed a methodology for unbundling the Cooperative's retail electric rates, which would be applied to the Cooperative's bundled rates to create a set of unbundled charges for the Cooperative's use after January 1, 2002. [4] Schedule 5A attached to Mr. Gaines' testimony sets forth the Cooperative's proposed rates, tariffs and revenue allocation. Schedule 6 sets forth sample bill comparisons using the Cooperative's Schedule A (Rural Electric Service) and Schedule B (Commercial and Small Power Service) current and proposed rates at a range of usage levels. For the Cooperative's Schedule LP (Large Power Service), Mr. Gaines provided the actual annual billing comparisons for each customer for the test year. (Ex. JG-2, at 2-4; Schedule 5A and 6).

Mr. Gaines designed the Cooperative's capped bundled rates to: (1) produce the Cooperative's aggregate test year revenue requirement; (2) moderately reapportion revenues among classes consistent with the bundled cost of service study; (3) provide a better basis for unbundling by adjusting rate components (consumer, demand, and energy) to better reflect component costs; and (4) design two new tariffs, Schedule LP-2 for customers served directly from a substation at 12,470 volts and Schedule SKI for seasonal operation of a large ski resort. (Ex. JG-2, at 14).

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[4] All of the parties agree that the Cooperative's unbundled rates and the methodology used for unbundling its rates should be addressed in Case No. PUE010002 (*Application of BARC Electric Cooperative, For a Functional Separation Plan*, D.C.C No. 010310018). I, likewise, agree and any further discussion in this Report will be limited to the Cooperative's capped bundled rates at issue in this case. (Cooperative Post-Hearing Brief at 30-31; Staff Post-Hearing Brief at 49-51; Consumer Counsel Post-Hearing Brief at 4).

Mr. Gaines testified the Cooperative's test year power cost was based on the currently effective Old Dominion Electric Cooperative ("ODEC") 2000/2001 wholesale rate level. As part of a Strategic Plan Initiative ("SPI"), ODEC planned a series of annual rate reductions in its wholesale power costs.[5] Mr. Gaines is unsure what level of SPI power cost the Cooperative should use to set its capped bundled rate. Except for the 3% it purchases from The Southeastern Power Administration ("SEPA"), the Cooperative must purchase the remainder of the capacity and energy it sells to its customers from ODEC. The Cooperative is an all-requirements power supply customer of ODEC. All of the Cooperative's costs for transmission services, including ancillary services, are bundled in the ODEC wholesale rate. Mr. Gaines used the Cooperative's total test year system purchased power cost, which included the amounts paid to ODEC for all energy and capacity requirements for resale to its customers, to represent the Cooperative's generation costs. (Ex. JG-2, at 17-19, 21-22).

On cross-examination, Mr. Gaines testified that the Cooperative's requested $815,679.00 increase in annual revenues included $204,685.00 in gross receipts taxes. Mr. Gaines agreed that as of January 1, 2001, the Cooperative would no longer be paying gross receipts taxes. (Tr. at 44-46; Ex. JG-3).

Mr. Gaines based his purchased power costs on the ODEC wholesale rate in effect for the period April 1, 2000, through March 31, 2001. He does not know whether ODEC will increase or decrease its wholesale rate in the future. However, if ODEC does adjust its wholesale rate, it has historically adjusted the rate on April 1 of each year. In all of his revenue and purchased power cost calculations, Mr. Gaines used the test year adjusted billing determinants, including a customer growth adjustment, extrapolating out one year following the test year, which would have been the billing determinants ending June 30, 2000. Mr. Gaines priced those billing determinants using the purchased power costs that were placed into effect on April 1, 2000. (Tr. at 47-50).

While he was unsure in his prefiled testimony what purchased power cost the Cooperative should use, Mr. Gaines testified on cross-examination that it is the Cooperative's position that the current level of purchased power costs should be used to cap rates. Mr. Gaines believes that a purchased power cost set at some level below what the Cooperative is currently paying will put the Cooperative at risk. Mr. Gaines believes the risk arises from the fact that the Cooperative will be unable to adjust the generation cap going forward. If the generation cap is understated, and the Cooperative's bundled rates are capped, the Cooperative could be at risk if generation costs increase. Even with the SPI, Mr. Gaines believes the evidence shows that ODEC's base rate has been going down, but the fuel component of its rate has been increasing dramatically. Notwithstanding the foregoing, Mr. Gaines confirmed that ODEC's demand rate, for the first 300 kW of demand at a distribution substation, decreased from $5,461.80 in 1999 to $5,243.33 in 2000. (Tr. at 51-54; 56-57; Ex. JG-4).

[5] Mr. Gaines described the SPI as a cash-to-market plan. In 1997, ODEC added a component to its revenue requirement and wholesale rate to generate additional cash through the year 2003. ODEC would use the cash to pay down its debt so that at the end of the SPI period its cost of service would be competitive in the marketplace. (Tr. at 60-61).

Responding to questions from the bench, Mr. Gaines testified ODEC produces about 50% of the power it sells to its member cooperatives, and it purchases the rest. Mr. Gaines believes that increases in ODEC's own fuel costs could be passed along to its member cooperatives and would be recoverable from the cooperatives' customers even under capped rates. Mr. Gaines was unsure how increases in ODEC's purchased power costs should be treated. He opined that if the cost increases were clearly due to increases in fuel costs, then those costs might be able to be passed through to the member cooperatives' customers under capped rates. However, if the cost increases were not considered fuel related, then ODEC would be placed in a position of having to adjust its base rates. (Tr. at 64-67).

On rebuttal, Mr. Gaines testified that the majority of the issues he raised in his prefiled rebuttal testimony have been resolved, except the issues concerning: the Staff's interpretation of the "forward look" requirements of § 56-582 A 3 of the Code of Virginia and the Staff's methodology used to take that look; and purchased power costs on a going-forward basis and their effect on the Cooperative's rates, the rates to be unbundled, and the generation cap that is established. Mr. Gaines believes the Staff's methodology used in this case is overly complex and uses projections that may or may not be reliable. Mr. Gaines believes the Commission should recognize the statutory requirement that once established, the approved rates would have to last through July 1, 2007. Mr. Gaines believes that "due consideration" means that the Commission may consider financial projections in establishing the required level of margins, TIER, or rate of return as part of the determination of test year revenue requirements. He would prefer that the Commission rely on a forecast similar to the Financial Status Statement that was included with Staff's Statement 1 Revised to establish the Cooperative's rates on a going-forward basis. Mr. Gaines also believes the Staff's treatment of ODEC's wholesale power costs under the SPI would cause the Cooperative to underrecover, in the amount of $1,073,236, its wholesale power costs through 2003. The Cooperative would recover those monies only if the reductions forecast by ODEC actually materialized. (Tr. at 123-31, 133; Ex. JG-14, at 2-4).

On cross-examination, Mr. Gaines testified if the generation cost is set too low for the Cooperative's bundled rate, he would argue that a different cost level should be used in the Cooperative's unbundled case to set the generation cap. Without the ability to adjust generation costs until 2007, Mr. Gaines believes a generation cost set below the current cost of generation exposes the Cooperative to an unacceptable degree of risk. (Tr. at 134-36; Ex. JG-14, at 5).

In his prefiled testimony, Mr. Hively explained the methods the Cooperative used to allocate jurisdictional revenues and expenses, and the procedure used in determining the proposed fees to be charged for various services. Mr. Hively's testimony related to Schedule 5A (Pgs. 22 & 23) (Terms and Conditions); Schedule 10 (Pgs. 117-127) (Support for Increased Fees); Schedule 11 (Revenue and Expense Variance); and Schedule 12 (Jurisdictional Allocation) filed as part of the Cooperative's Application. In addition, Mr. Hively sponsored the Cooperative's Application into evidence. (Tr. at 70; Ex. CH-5, at 2; Ex. CH-6).

The Cooperative proposes to increase the following fees: Collection $15.00 to $25.00; Reconnection Normal Hours, $30.00 to $50.00; 3-Month Meter Readings, $10.00 to $20.00; Connection or Reconnection After Hours, $75.00 to $85.00; Bad Check Charge, $10.00 to $20.00; Connection Fee Normal Hours, $10.00 to $20.00; Yard Light Pole and Guy Installation, Total Cost.

The Cooperative determined the new fee structure by determining the estimated direct labor cost, fringe benefit cost, and travel cost for each activity. The Cooperative then divided the total cost by the annual number of such fees applied during the test year. The proposed fee increases are expected to generate an additional $49,640.00 in revenue for the Cooperative. (Ex. CH-5, at 3, Schedule 5B Pg. 3).

There was no cross-examination of Mr. Hively. (Tr. at 69).

Mr. Barker was the first witness to testify for the Staff. Mr. Barker revised his Statement 1; Schedule E to Statement 1; Jurisdictional Billing Determinants; Financial Status Statement; Adjustment to Customer Growth Street Lights; Adjustment No. 1D; Adjustment No. 1C; and Appendix, pages 18-28 of his prefiled testimony. Mr. Barker testified these revisions resulted from changes in two of his adjustments. The first was a change to his revenue adjustment. The Staff had incorrectly calculated the revenue associated with street lights. The rate charged for street lights within each rate class was different from the class rate and resulted in an incorrect calculation of revenue for the class. To correct this error, Mr. Barker removed the amount of kilowatt-hours from each rate class associated with street lights, and then added the actual revenue generated from each customer in that class who had a street light. This change resulted in an increase in jurisdictional revenue of $71,187.00. The second change occurred to purchased power expense. Mr. Barker added the flat station charge for each delivery point for each month, and then he removed the first 300 kW from each of the distribution and transmission demand charges. The net effect of these two changes increased the Staff's recommended increase in the Cooperative's revenue requirement from $492,910.00 to $524,787.00. (Tr. at 75-77).

Mr. Barker testified that purchased power expense represents approximately $102,000.00 of the Cooperative's $524,787.00 additional revenue requirement. He calculated the Cooperative's total purchased power expense for the period 2001-2007 as $5,591,085.00. Of this amount, approximately $80,996.00 represents fuel costs. (Tr. at 77-78).

In his revised supplemental testimony, Mr. Barker explained the Staff's use of a present value factor in determining the Cooperative's future cost of service. The Staff used the present value of all rate period revenues, expenses, and rate base items, because certain cost of service items, such as purchased power expense, are not projected to change at a constant rate during the rate period. Additionally, if the Staff had used nominal dollars for all rate period cost of service items, the Staff's billing determinants and revenue requirement would not be as comparable to the Cooperative's. Mr. Barker stated the use of present value amounts results in a more accurate average cost of service throughout the rate period, and more closely approximates the pro forma revenue and billing determinants used by the Cooperative. (Ex. JB-8, at 1).

Mr. Barker further explained why the 2001-2007 rate period produces a lower revenue requirement than the 2001 adjusted rate year. Apparently, in nominal dollars, revenues will increase at a slightly faster rate than overall expenses during the rate period. The Staff's adjusted nominal base rate revenue increases from $12,545,495.00 during the 2001 rate year to $15,161,743.00 in 2007, an average increase of 3.20%. The Cooperative's four major expense items (purchased power, operations and maintenance, depreciation, and interest) are projected to increase in nominal dollars from $11,894,094.00 in the 2001 rate year to $14,012,977.00 in 2007, an average annual increase 2.77%.[6] Since revenues are projected to increase by 3.20% and expenses are projected to increase by 2.77% for the period, the Cooperative's TIER increases from 1.77 to 1.85 and its revenue requirement decreases from $591,770.00 to $524,787.00, the Staff's recommended revenue requirement. (Ex. JB-8, at 2-3).

Mr. Barker compared the Staff's recommended revenue requirement of $524,787.00 to the Cooperative's proposed revenue requirement of $815,679.00. In order to compare the two, Mr. Barker first removed the gross receipts taxes included in the Cooperative's revenue requirement. After January 1, 2001, the Cooperative was no longer responsible for paying gross receipts taxes. This reduces the Cooperative's revenue requirement to $610,994.00. Since the Cooperative and the Staff used different billing determinants, the Staff's revenue requirement of $524,787.00 has to be grossed up to make the two proposed revenue amounts comparable. This results in a revenue requirement of $529,810.00, which produces a base rate increase of approximately 87% of that proposed by the Cooperative. (Ex. JB-8, at 3-4).

Mr. Barker addressed several points raised in Mr. Mitchell's rebuttal testimony. First, the Staff agreed with the Cooperative that the Staff's proposed booking changes to property taxes and payroll taxes do not need to be made in this case. The Cooperative provided sufficient evidence that RUS changed the guidelines for booking these taxes and the Cooperative is complying with the revised guidelines. Secondly, the Staff strongly disagreed with the 10% depreciation rate used by the Cooperative in several of its plant accounts. Mr. Barker argued the Cooperative has not obtained permission from the Commission to use the rates in question, nor has the Cooperative provided estimates of the equipment's useful life, as is recommended by RUS. In the past, the Staff has approved depreciation rates that are outside the approved RUS range, but the Cooperative has not requested such approval. If prior approval has not been sought, the Staff has adjusted the depreciation rates to the top of the RUS range. The Commission has approved such adjustments. (Tr. at 83-85).

Mr. Barker also responded to Mr. Gaines' rebuttal testimony concerning the possibility the Cooperative would underrecover its purchased power costs during the rate period. Mr. Barker stated the Staff calculated the Cooperative's TIER, using nominal dollars, for each of the years in the rate period. The Staff found that the lowest TIER produced in any year was 2.1 in 2002, and the highest was 2.45 in 2004. Mr. Barker argued the resulting TIER is well above the minimum needed to meet RUS loan requirements.[7] According to Mr. Barker, any underrecoveries during the first few years of the rate period would be more than made up from the overrecoveries that would result in the later years of the rate period. Finally, Mr. Barker testified the Staff used ODEC's most recent economic forecast of purchased power rates to project the Cooperative's purchased power costs going forward. (Tr. at 86-88; Ex. JB-7, at Appendix 32-36).

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[6] The Staff has projected that purchased power expense will increase from $6,611,364.00 in the 2001 rate year to $7,018,864.00 in 2007, an average annual increase of 1.10%; operations and maintenance expense will increase from $2,875,426 in the 2001 rate year to $3,572,309.00 in 2007, an average annual increase of 3.68%; depreciation expense will increase from $1,183,215 in the 2001 rate year to $1,603,502 in 2007, an average annual increase of 5.20%; and interest expense will increase from $1,224,089 in the 2001 rate year to $1,818,302 in 2007, an average annual increase of 6.82%. (Ex. JB-8, at 2-3).

[7] The minimum TIER for the Cooperative to borrow funds from the Federal Financing Bank ("FFB") is 1.25 in any two out of three calendar years. (Tr. at 95-96).

On cross-examination, Mr. Barker admitted the methodology used by the Staff in this case has not been used before; but then again, the entire forward-looking concept is new to the Staff. He testified he obtained his SPI demand cost reduction of 4% per year between 1999 and 2002, 11% reduction in 2003 and 2004, 2% increase in 2005, no change in 2006, and 1% increase in 2007 from ODEC's August 28, 2000, rate projections supplied to its member cooperatives. According to Mr. Barker's understanding of the SPI, without it, the Cooperative's purchased power rates would be even lower. The SPI allowed ODEC to charge higher power rates to its member cooperatives, and ODEC used the additional cash generated by those rates to pay down its debt. (Tr. at 90-94).

Mr. Barker used the depreciation rates that are in the RUS-approved ranges in his testimony including the accounts containing the load management equipment. Mr. Barker was not familiar with other cooperatives' load management equipment depreciation rates. He testified the Commission did not specifically approve depreciation rates in the Cooperative's last two rate cases. The Staff believed it was not constrained to accept the Cooperative's depreciation rates. The first indication the Cooperative received that the Staff disagreed with its 10% depreciation rate for load management equipment was when the Staff prefiled its testimony in this case. Mr. Barker could find no information that depreciation rates were an issue in the Cooperative's last two rate cases. (Tr. at 97- 101).

In his prefiled direct testimony, Mr. Ballsrud addressed the appropriate interest expense to be used to calculate earnings and the appropriate TIER for the Cooperative. He also sponsored the methodology used by the Staff for combining multiple calendar year nominal amounts into one rate period using a discount factor based on the Cooperative's annual embedded cost of long-term debt. (Ex. JRB-9, at 1).

Mr. Ballsrud calculated the Cooperative's annual interest expense for 2000 to be $1,247,674.00. He further calculated an interest expense for 2001 of $1,346,262.00, which increases to $1,999,782.00 in calendar year 2007. Mr. Ballsrud based these interest expense amounts on pro forma December 31 debt balances that are consistent with the funds required to meet plant investment as calculated by Staff witness Barker. Mr. Ballsrud agreed with the Cooperative's cost rates for existing RUS and National Rural Cooperative Finance Corporation ("CFC") debt with two exceptions. First, all FFB borrowings would be made at an interest rate of 6.13% (compared to 6.75%). Second, all CFC interest rate renewals would be made at 9.10% (compared to 7.15%). Finally, Mr. Ballsrud agreed to use July 1 for the drawdown date for new debt in each year of the rate period. (Ex. JRB-9, at 1-2).

Based on a comparative analysis of the Cooperative's financial condition to its peers and its own historical performance, Mr. Ballsrud believes a TIER range of 2.00 – 2.50 is appropriate for the Cooperative. He recommends setting the Cooperative's rates at the midpoint of the range. With rates set at this point, the Cooperative's margins for 2001 are $938,933.00, resulting in a debt service coverage ("DSC") ratio of 1.90. Mr. Ballsrud believes this level of margins should allow the Cooperative's equity ratio to grow toward its target level of 40%. Mr. Ballsrud further believes this level of margins should satisfy the statutory requirements of § 56-231.33 of the Code of Virginia by maintaining the Cooperative's property in a sound physical and financial condition, maintaining its financial integrity at a level that will allow it to raise capital on reasonable terms, and recovering additional amounts to meet any debt indenture approved by the Commission. (Ex. JRB-9, at 2).

Mr. Ballsrud compared the Cooperative's financial performance to that of the other Virginia electric cooperatives. He found that from 1995 to 1999, the Cooperative's TIER was 1.84, as compared to the average Virginia TIER of 2.45, and the national average TIER of 2.44. From 1995 to 1999, the Cooperative's DSC ratio was 2.01 compared to the average Virginia DSC of 2.42, and the national average DSC of 2.21. The Cooperative's financial performance as measured by both TIER and DSC was below the industry average. In addition, the Cooperative's historic equity ratio has not compared favorably to that of its peers. By year-end 1999, the Cooperative's equity to total capital ratio was 38.20% compared to the Virginia average of 46.85%, and the national average of 48.7%. (Ex. JRB-9, at 16-17).

Mr. Ballsrud discussed the methodology he used to develop a rate period that covers the period 2001 to 2007. In the past, public service companies focused on revenues and expenses in either a test year or rate year when they filed for a rate increase. Under the Virginia Electric Restructuring Act (the "Restructuring Act") most electric utilities were permitted to increase their rates effective January 1, 2001, but those rates would be effective through 2007. Mr. Ballsrud believes the Act requires the Commission to look at revenues and expenses through 2007, making the rate period seven years. Mr. Ballsrud believes that simply adding up revenues and expenses in nominal dollars over a seven-year period of time to arrive at a total would ignore the time value of money, which is central to finance theory. He described finance theory as a mechanism that allows a stream of dollars over multiple years to be added properly. The dollars from each of the years would be discounted to create a net present value ("NPV") for the base year. Mr. Ballsrud testified the Staff routinely uses NPV and internal rate of return ("IRR") methodologies in determining the effective cost rate for debt and preferred securities in utility rate cases. (Ex. JRB-9, at 5-6).

Mr. Ballsrud further explained that finance theory does not supply the discount rate that should be used. In order to determine the correct rate, Mr. Ballsrud looked at the Cooperative's financing options. Although the Cooperative has lines of credit at commercial banks, Mr. Ballsrud believes the only reliable sources of long-term financing are RUS, CFC, or National Bank for Cooperatives ("CoBank"). He also believes the embedded cost of the Cooperative's entire debt portfolio would be a better, more stable, discount rate to apply in this case. Mr. Ballsrud calculated the Cooperative's embedded cost of debt for 2002 to be 6.122%. He then used this method to calculate the discount factors for 2003 through 2007. (Ex. JRB-9, at 6-7).

On direct examination, Mr. Ballsrud testified he relied on information supplied by the Cooperative in developing his interest expense numbers. The information included the amount borrowed, the term of the loan, the interest rate, and the lender. (Tr. at 107-08; Exs. JRB-10, JRB-11).

Mr. Ballsrud sponsored into evidence a credit update on ODEC prepared by Fitch, Ibca, Duff & Phelps. The report mentions the SPI and the four-percent reduction in the demand rate to its member cooperatives. Mr. Ballsrud used this report to examine the credit worthiness of ODEC, and how its member cooperatives were affected by the SPI. (Tr. at 109-10; Ex. JRB-12).

Mr. Ballsrud responded to the Cooperative's rebuttal testimony. Mr. Mitchell stated that Mr. Ballsrud failed to annualize the interest expense on the two FFB notes issued during 2000. Mr. Ballsrud explained that he used a different methodology than Mr. Mitchell and that his methodology did, in fact, account for the interest on the two notes. Mr. Ballsrud calculated the annual amount of all funds drawn during 2000, plus a portion of the interest for debt that was drawn in 2000. In his calculations, Mr. Ballsrud used those amounts plus a portion of the interest as if the Cooperative had drawn the note on July 1, 2001. Mr. Ballsrud used the July 1 date because both the Staff and the Cooperative showed July 1 as the date for all future borrowings from the government. (Tr. at 111-12).

Mr. Ballsrud also responded to Mr. Gaines' rebuttal. He believes Mr. Gaines' interpretation of "due consideration" means no consideration. Mr. Ballsrud defended the Staff's attempt to quantify and refine the estimates that it used in this case. He believes the Staff examined its estimates in sufficient detail that it can make a meaningful prediction of the ultimate outcomes. He further believes the Staff's methodology of using a seven-year rate period that is present valued gives a balanced, results-oriented evaluation of the Cooperative's financial position. (Tr. at 113-14).

There was no cross-examination of Mr. Ballsrud. (Tr. at 114).

In her prefiled direct testimony, Ms. Henderson addressed the Cooperative's cost of service study, proposed revenue allocations, changes in rate design and terms and conditions for service, and the effects of such proposed changes on the Cooperative's customers. (Ex. RH-13, at 1).

Ms. Henderson summarized the Cooperative's application for a rate increase. The Cooperative proposed to allocate the rate increase among its jurisdictional retail classes in the following manner:

Schedule A (Rural Electric)	$716,393.00	7.98%
Schedule B (Commercial-Single Phase)	$ 15,930.00	3.05%
Schedule B (Commercial-Three Phase)	$ 6,933.00	5.97%
Schedule LP (Large Power)	$ 16,287.00	0.98%
Schedule Y (Yard Lighting)	$ 10,496.00	6.21%
Subtotal	$766,039.00	6.69%
Other Electric Revenue (Service Charges)	$ 49,640.00	24.09%
Total Revenue Increase	$815,679.00	7.00%[8]

Ex. RH-13, at 2.

Ms. Henderson testified the Cooperative, pursuant to the Commission's Final Order in the Cooperative's last general rate case, filed a cost of service study as part of its Application. The Staff agreed with the Cooperative's allocation methodology for separating its jurisdictional and non-jurisdictional customers, and its methodology for accounting for yard light expenses, revenues

[8] The Cooperative's filed Application includes gross receipts taxes, which are embedded in these numbers. The Cooperative's proposed revenue increases with gross receipts taxes and after removal of gross receipts taxes from both present and proposed revenues are shown in Exhibit RH-13, at 7.

and plant investments. Consequently, the Staff did not conduct its own cost of service study. In addition, the Staff recommended no changes in the rate structures for any of the service classes. (Ex. RH-13, at 3-6).

Ms. Henderson recommended that the Cooperative's Wholesale Power Cost Adjustment Clause ("WPCAC") be amended because it presently includes an adjustment for state and local gross receipts taxes and the special regulatory revenue tax. She recommends that the WPCAC be amended to remove the references to adjustments for gross receipts taxes in paragraphs A – Wholesale Rate Changes; B – Fuel Cost Adjustment; and C – Definition of Terms. (Ex. RH-13, at 8).

Ms. Henderson testified the Cooperative's Application did not include a functional unbundling plan. The Cooperative proposed a methodology for unbundling its rates, but it could not identify the appropriate level of generation cost to unbundle. The Staff believes the generation costs identified in the bundled capped rates approved in this case should be the generation costs used in unbundled rates to calculate any associated wires charges. The Staff recommended that the Commission defer any decision on unbundling the Cooperative's rates to another proceeding. (Ex. RH-13, at 10-12).

Ms. Henderson testified the Staff has no objection to the Cooperative's miscellaneous service charges, including the Cooperative's proposed $20.00 bad check charge. The Staff further supports the Cooperative's change in its meter reading policy. The Cooperative will now render two, not three, consecutive estimated bills before the Cooperative reads the meter and a fee is added to the customer's bill. The Staff also supports the Cooperative's changes to its generation credit rider. The change limits the application of the credit to generation by a consumer who purchases his generation and transmission service from the Cooperative, eliminating participation in the credit by a retail access customer who receives generation service from another supplier. (Ex. RH-13, at 12-15).

Finally, Ms. Henderson testified the rates and charges discussed in her testimony reflect the per books data provided by the Cooperative in its Application. If the Commission approves an increase in revenue, prior to the implementation of the increase, the Cooperative's rates and charges must be adjusted to reflect the Commission's findings regarding revenues, accounting adjustments, gross receipts tax removal, and purchased power cost. If the Commission approves a revenue increase that differs from the increase proposed by the Cooperative, the increase should be allocated to the retail classes in the same percentages as proposed by the Cooperative. (Ex. RH-13, at 16).

On cross-examination, Ms. Henderson reiterated the Staff's position that the Cooperative's bundled capped rates approved in this case should be the generation costs used in the unbundled rates to calculate any wires charges. The purchased power cost in this case should be the basis for functional unbundling. (Tr. at 120-22).

DISCUSSION

At the direction of the Hearing Examiner, the parties filed a joint case issues which identifies the issues that the Commission needs to decide in this case.[9] At the center of the controversy between the parties is the methodology to be used for setting capped rates. The Cooperative argues in favor of one methodology, and the Staff and Consumer Counsel argue in favor of another. The resolution of this issue will, by necessity, resolve the accounting issues related to: whether adjustments to cost of service should be made for the period 2001 through 2007, or for the rate year; billing determinants; and purchased power cost and the period over which purchased power will be measured. In addition, it will resolve the cost of capital and finance issues related to whether adjustments to the cost of capital should be made for the period 2001 through 2007, or for the rate year. Each of the parties believes his position is supported by the language of § 56-582 A 3 of the Code of Virginia.

The statute at issue provides, in part, that:

> Such rate application [for capped rates] and the Commission's approval shall give due consideration, on a forward-looking basis, to the justness and reasonableness of rates to be effective for a period of time ending as late as July 1, 2007.

§ 56-582 A 3 of the Code of Virginia.

In its post-hearing brief, the Cooperative argues the statute has not altered the "just and reasonable" requirement for rates found in existing statutes. The Cooperative argues its rates must be set such that it has an opportunity to earn a rate of return sufficient to allow it to attract the capital necessary to render service to the public. In making this determination, the Commission must recognize that the rates it sets will remain in effect, unchanged, until July 1, 2007. The Cooperative does not believe the "forward look" set forth in the statute requires an annual look at revenues, expenses, and rate base for each year in the period. The Cooperative likens the Staff's methodology employed in this case to "voodoo ratemaking." The Cooperative believes the Staff has relied on "a mix of shaky assumptions and uncertain predictions in its analysis." In this time of transition to retail electric competition, the Cooperative believes the Commission should not adopt the Staff's untried and untested methodology, which it believes may increase and exacerbate the risk faced by the Cooperative during the transition period. (Cooperative Post-Hearing Brief at 14-16).

The Cooperative believes the requirements of the Restructuring Act dovetail with Virginia's existing laws governing the regulation of public utilities and their rates. In support of its position, the Cooperative cites *Scott v. Lichford*, 164 Va. 419, 422, 180 S.E.2d 393, 394 (1935) ("Repeal by implication is not favored and the firmly established principle of law is, that where two statutes are in apparent conflict, it is the duty of the court, if it be reasonably possible, to give them such a construction as will give force and effect to each."). The Restructuring Act incorporates the provisions of Chapter 10 of Title 56, which includes § 56-235.2 of the Code of Virginia. This statute provides: "[i]n determining costs of service, the Commission may use the test year method

[9] *See*, Case Issues, D.C.C. No. 010210291, February 9, 2001.

of estimating revenue needs, but shall not consider any adjustments or expenses that are *speculative* or cannot *be predicted with reasonable certainty*." (Emphasis added). The Cooperative believes the Commission can give due consideration to the justness and reasonableness of its rates on a forward-looking basis pursuant to § 56-582 A 3 of the Code of Virginia, provided the determination of such rates is not based on adjustments or expenses that are speculative or cannot be predicted with reasonable certainty, as prohibited by § 56-235.2 of the Code of Virginia.

The Staff applied the "plain meaning rule" of statutory construction to § 56-582 A 3 of the Code of Virginia finding that the statute applies to any rate application of an incumbent electric utility, including electric cooperatives.[10] The Staff interpreted "due consideration" to mean "[t]he degree of attention properly paid to something, as the circumstances merit." *Black's Law Dictionary* 516 (rev. 7th ed. 1999). Although the Restructuring Act fails to define "justness and reasonableness of rates," the Staff found that §§ 56-235.2 and 56-231.33 of the Code of Virginia supply the meaning of "justness and reasonableness" of rates for purposes of § 56-582 A 3 of the Code of Virginia.[11] The Staff argues the Restructuring Act requires the Commission to consider the cost of service elements enumerated in §§ 56-235.2 and 56-231.33 of the Code of Virginia for the period beginning January 1, 2001, and ending as late as July 1, 2007, and to include in rates major identifiable changes to cost of service that are projected to occur during that rate period. (Staff Post-Hearing Brief at 8-11).

Consumer Counsel argues the Commission must look at the justness and reasonableness of the Cooperative's rates "on a forward-looking basis." However, the statute also provides the Commission with discretion within the phrase "due consideration." The Commission should evaluate the particular facts of each proceeding, on a case-by-case basis and give "due consideration" to the justness and reasonableness of rates for a period ending as late as 2007. Consumer Counsel believes "due consideration" necessarily involves looking at factors that may impact the justness and reasonableness of those rates during the entire period. Consumer Counsel believes the Staff's methodology looks at both projected increases and decreases in the Cooperative's expenses. Consumer Counsel does not oppose the Staff's rate proposal in general, and supports the Staff's use of the purchased power costs resulting from the SPI. (Consumer Counsel Post-Hearing Brief at 2-3).

The intent of § 56-582 A 3 of the Code of Virginia may be determined if one looks at the statute's component parts. First, the language "due consideration" provides the Commission the discretion to review the various factors that affect the justness and reasonableness of an electric utility's rates. Such factors would include the utility's revenues, expenses, and rate base. This discretion allows the Commission to weigh the evidence in determining just and reasonable rates. Second, the phrase "on a forward-looking basis" requires the Commission to look into the future, evaluate the components that make up a utility's rate, and determine whether those components are trending up or down. In the exercise of this duty, the Commission would have to rely on forecasts of the utility's revenues, expenses and changes in rate base in reaching its decision whether the

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[10] *See, State Bd. For Contractors v. H.B. Sedwick, Jr. Bldg. Supply Co., Inc.*, 234 Va. 79, 83, 360 S.E.2d 169, 171 (1987) ("when the language of a statute is unambiguous, the statute's plain meaning must be accepted and rules of statutory construction are not required.").
[11] Section 56-235.2 of the Code of Virginia defines "just and reasonable" rates for public utilities. Section 56-231.33 of the Code of Virginia defines "reasonable and just" charges for distribution cooperatives.

utility's rates will be just and reasonable in the future. The Commission, in the exercise of its discretion, would weigh the reliability of the data and assumptions used in the forecasts in determining whether the utility's rates meet the just and reasonable standard. Finally, the phrase "for a period of time ending as late as July, 1, 2007," provides the ending date of the period given to the Commission to consider whether a utility's rates are just and reasonable. The statute establishes a rate period that is seven years in duration for this case. The Commission's duty is to balance the interests of the utility and its customers in determining whether rates that are set in 2001 will remain just and reasonable for both parties throughout the period 2001 through 2007. If expenses are forecasted to increase during the period, the utility should be entitled to additional revenue. If expenses are forecasted to decrease during the period, the utility's customers should be entitled to lower electric rates. The Commission must decide whether the forecasts are reliable. The statute has granted the Commission the power to exercise its best judgment in looking at future economic forecasts to reach its decision on just and reasonable rates for the entire period. After July 1, 2007, the market, not the Commission, will determine what rates are just and reasonable.

Although the Cooperative has argued that the Staff has relied on "voodoo ratemaking" and "shaky assumptions and uncertain predictions," I find the Cooperative's argument lacks merit. The Cooperative's objections to the Staff's methodology focus on two points: the Staff's use of a present value factor on its out-year revenues and expenses, and the Staff's use of ODEC's wholesale power cost forecast in setting the Cooperative's purchased power cost. I find the methodology employed by the Staff in this case is reasonable and meets the requirements imposed on the Commission by § 56-582 A 3 of the Code of Virginia.

The Staff performed a detailed analysis of the Cooperative's current and projected revenues, expenses, and changes in rate base for the 12 months ending June 30, 1999, through July 1, 2007. The Staff relied on the most current data available from the Cooperative and ODEC, its primary wholesale power supplier, in reaching its conclusions and making its recommendations to the Commission. The Staff used a seven-year rate period to determine the Cooperative's revenue requirement and applied a present value factor to the out-year revenues and expenses to reflect a 2001 rate year. The Cooperative objects to the use of a present value factor and would prefer, if the Commission were to rely on such an analysis, that nominal dollars be used. The Staff's rationale for applying a present value factor appears reasonable. The present value factor was used to account for the different percentage increases in purchased power expense, operations and maintenance expense, depreciation expense, and interest expense occurring over the period, and to recognize the time value of money. The Cooperative's revenues are increasing at a faster rate than the Cooperative's expenses. The use of the present value factor permits a meaningful comparison of the Cooperative's revenues and expenses over the entire rate period. Even if one were to use nominal dollars, as suggested by the Cooperative, the Staff's methodology still produces a TIER that ranges from 2.10 to 2.45 during its rate period, which further supports the reasonableness of the Staff's methodology.

The Cooperative's use of traditional ratemaking methodology, test year/pro forma year, fails to take into account that rates set in 2001 must be just and reasonable not only for the Cooperative, but also for its customers, for the entire seven-year rate period. If significant reductions in expenses are forecasted in the future, these reductions should be reflected in the rates to be paid by the Cooperative's customers. The Cooperative's methodology fails to take the forecasted reductions from ODEC's SPI into consideration. The Cooperative particularly objects to the Staff's use of the purchased power forecasts that were part of the SPI and the rate projections supplied by ODEC to its member cooperatives in August 2000. The Cooperative characterizes these forecasts as speculative or unreliable. I find this position somewhat tenuous given the fact that ODEC supplied the forecasts to its member cooperatives with instructions that they "should be used as a tool for developing your strategy for dealing with the rate caps." *See*, Ex. JB-7, Attachment A. ODEC, not the Cooperative, should be the best judge of its future wholesale power costs. The evidence indicates that, at least within the financial community, ODEC appears to have achieved the objective of the SPI, reducing its base power costs to make itself more competitive. The evidence further indicates that, were it not for the SPI, the Cooperative's purchased power costs would be even lower. I find the August 2000 rate projection forecast prepared by ODEC, and supplied to its member cooperatives, represents the best estimate of the Cooperative's future purchased power costs and may be relied upon for making rates in this case. The Cooperative's customers should be afforded the benefits of the Cooperative's reduced purchased power costs.

There are five accounting issues in dispute: gross receipts taxes, depreciation expense, rate case expense, right-of-way expense, and payroll expense.

I find that gross receipts taxes should be removed from the Cooperative's revenue requirement. After January 1, 2001, the Cooperative is no longer responsible for paying gross receipts taxes. The Cooperative's customers are now directly responsible for paying a consumption tax, which is separately identified on their bills. This adjustment has the effect of reducing the Cooperative's requested revenue requirement from $815,679.00 to $610,994.00.

Depreciation expense has the next largest impact on the Cooperative's revenue requirement. In support of a 3.07% depreciation rate for its distribution plant equipment, the Cooperative argues that RUS guidelines require it to select a depreciation rate at or near the midpoint of its composite depreciation range of 2.68% to 3.31%. In support of its 10% depreciation rate on its load management equipment, the Cooperative argues it has used this rate since 1988, the 10% rate is reasonable, and the 10% rate actually reflects the useful life of such equipment. The Staff opposes the use of these depreciation rates. It argues the Cooperative did not use accepted RUS depreciation rates on its distribution plant equipment. The Staff further argues the Cooperative did not obtain permission from the Commission to use the 10% depreciation rate on its load management equipment, and the Cooperative failed to show the load management equipment's useful life was ten years. The record indicates that RUS will accept a depreciation rate for distribution plant equipment that is set at or near the midpoint of the Cooperative's composite depreciation range. The record further indicates that the Cooperative started purchasing its load management equipment in 1988, the manufacturer of the equipment is no longer in business, the equipment purchased by the Cooperative is obsolete, newer models of the same equipment are being phased out, the supplier of such equipment depreciates similar equipment over five years, and after more than ten years of use the Cooperative is considering replacing the equipment. In light of this evidence, I find the Cooperative's use of a 3.07% depreciation rate for its distribution plant equipment is reasonable. I likewise find the Cooperative's use of a 10% depreciation rate for its load management equipment is reasonable. The use of a 10% depreciation rate for this equipment produces a composite depreciation rate of 3.258%, which is still within the Cooperative's RUS composite depreciation range of 2.68% to 3.31%. Using the Staff's methodology and the Cooperative's depreciation rates produces an adjusted revenue requirement of $615,222.00, or $4,228.00 above the Cooperative's revenue requirement after gross receipts tax expenses are removed, and $90,435.00 above the Staff's recommended revenue requirement of $524,787.00.

At the beginning of the hearing, the Examiner expressed his concern with the amounts included in the Application for rate case expense, right-of-way maintenance, and payroll expense for a lead tree trimmer. With regard to rate case expense, the Hearing Examiner opined that extensive discovery prior to the evidentiary hearing may have unduly burdened the Cooperative. The Hearing Examiner also questioned, given the Cooperative's remote service area, whether the Cooperative was performing adequate right-of-way maintenance. In view of these concerns, the Hearing Examiner provided the Cooperative an opportunity to supplement the record on these issues. The Cooperative failed to take advantage of this opportunity. Therefore, I find the rate case expense, as adjusted by the Staff, is reasonable. The Cooperative put on no evidence that it incurred any additional expense as a result of the discovery propounded by the Staff. I further find the Staff's adjustments to right-of-way maintenance and removal of the lead tree trimmer's salary from payroll expense are reasonable. The Cooperative's cost of performing weed control in its rights-of-way increased by approximately 3% from the test year to the pro forma year, an increase of $6,967.00. For the same period, the Cooperative's cost for tree trimming declined by 6.3%, a decrease of $37,483.00. The Cooperative failed to explain why its right-of-way maintenance expense declined so dramatically from the test year to the pro forma year. Absent any other evidence to the contrary, I find that the Staff's adjustment to right-of-way expense is reasonable. Likewise, the Cooperative's lead tree trimmer position has been vacant for some time and there is no evidence the Cooperative plans to fill this position. Under these circumstances, I find the Staff's removal of the lead tree trimmer's salary from payroll expense is reasonable.

There are three issues related to cost of capital and finance that remain in dispute: interest expense, the appropriate TIER range, and the methodology for estimating the Cooperative's cost of capital for the period following the test year.

Staff and the Cooperative used different accounting treatments for the interest the Cooperative paid on its loans. The evidence indicates the Cooperative borrowed funds in February and June 2000. The evidence further indicates that in the future the Cooperative will borrow funds needed to support its operations on July 1 of every year. The Cooperative annualized the interest that would be paid on these loans. On the other hand, the Staff calculated the interest that would actually be paid for the remainder of the year the loan was drawn and then calculated the interest expense for each year thereafter. The Cooperative argues the Commission has permitted annualized interest in the past. The Staff argues its calculation reflects the Cooperative's true interest expense. I find the Staff's interest expense calculation is reasonable and should be used in this case. The Cooperative's methodology has the effect of slightly overstating its interest expense.

The Cooperative's proposed rate increase produces a TIER of 2.07. The Staff recommended a TIER range of 2.0 to 2.5 and further recommended the Cooperative's TIER be set at 2.25, the mid-point of the range. The Staff compared the Cooperative's financial performance to its Virginia and national peers and found that its performance lagged behind the average of its peer group. The Staff believes a 2.25 TIER would allow the Cooperative to improve its financial performance and reach its targeted equity ratio of 40%. The Cooperative believes the 2.25 TIER proposed by the

Staff is financially more sound than the TIER it proposed. I find that the Staff's recommended 2.25 TIER is reasonable. The evidence indicates that the Cooperative's financial performance has declined over the last few years. The 2.25 TIER allows the Cooperative to reverse this trend and ensures that it meets the statutory requirements set forth in § 56-231.33 of the Code of Virginia, in terms of its ability to maintain its financial integrity and attract capital at reasonable terms.

The Cooperative opposes the Staff's methodology used to estimate the Cooperative's cost of capital for the period following the test year. The Cooperative supplied the Staff with information on its existing notes and projected construction budget. The Staff determined that, due to changes in the RUS lending program, the Cooperative would obtain all of its future financing from the FFB. The Staff projected the interest rate for the Cooperative's FFB notes and CFC notes that are subject to being repriced during the rate period. The Staff used a methodology similar to the FFB's methodology for determining the interest rates for renewals and arrived at an estimated interest rate of 6.130% for future FFB notes; the Cooperative calculated an estimated interest rate of 6.75%. The Staff calculated its 9.10% estimated interest rate for CFC notes by averaging the remaining life of each note, which resulted in an average of 17.5 years. The Staff selected the current CFC rate for 20-year renewals, 9.10%, for use in its calculations. The Cooperative estimated the interest rate on CFC renewals at 7.15%. I find the Staff's methodology for determining the Cooperative's cost of capital is based on sound financial judgment and appears to produce a more accurate forecast of the Cooperative's future cost of capital. I recommend the Commission accept the Staff's 6.130% interest rate for new FFB notes and its 9.10% interest rate for CFC renewals.

The parties raised issues related to the proper methodology for unbundling the Cooperative's rates and the resulting unbundled rates for the Cooperative. I find these issues are best addressed in the Cooperative's functional separation case, Case No. PUE010002.

The final issue is whether the purchased power costs established in this case should be used to establish the capped generation rates in the Cooperative's functional separation case. The Staff argues this proceeding effectively sets the generation cap for the Cooperative's bundled rates, and this generation cap should be used in the Cooperative's unbundled rates to calculate any associated wires charge. The Staff argues the revenue requirement established in this case implicitly contains a generation component as part of the cost of service. It argues the generation component for bundled and unbundled rates should be the same otherwise a subsidy between bundled and unbundled customers may result, and the Cooperative may not recover the revenue requirement approved by the Commission in this case. The purchased power expense or generation cap supported by the Staff is $5,591,085. (Staff Post-Hearing Brief at 51-53).

The Cooperative argues it is essential that the capped rates for generation not be set too low, because these rates will remain in effect for the next several years. The Cooperative argues that under the Restructuring Act the non-generation components can be adjusted in a few years, but the capped generation rates cannot be adjusted until July 1, 2007. The Cooperative considers the risk associated with capped generation rates that are set too low to be much more significant than the risk associated with setting the non-generation components of its rates too low. The Cooperative argues the Staff's capped generation cost component for the Cooperative is set at a rate below the Cooperative's current generation costs. The Cooperative considers this a substantial risk and an untenable position for the Cooperative. (Cooperative Post-Hearing Brief at 27-30).

The evidence in this case indicates that ODEC's demand rate is decreasing but the fuel component of its rate is increasing. Under the Restructuring Act, § 56-582 B of the Code of Virginia, the Commission may adjust a utility's capped rates to account for increases in fuel costs, or if the utility finds itself in any financial distress beyond its control. The Commission may make these adjustments at any time during the transition period and as many times as may be necessary. The Restructuring Act, § 56-582 C of the Code of Virginia, further permits a utility to petition the Commission for a one-time change in the non-generation components of its rates. It appears the only risk faced by the Cooperative would be if ODEC increases its demand rate during the transition period. ODEC has forecasted declining demand costs until 2004, and then modest increases until 2007. This evidence is largely unrebutted by the Cooperative. The Staff factored ODEC's forecasts into its methodology. The Cooperative argues the Commission should not rely on ODEC's forecast of its own wholesale power costs; however, the Cooperative has never stated that the methodology or the assumptions used in the forecast were flawed. In reviewing the forecast, it appears the assumptions that are subject to the greatest degree of volatility are related to weather and the cost of increasing capacity, as well as fuel costs. These costs may be recovered under capped rates.[12] On this record, I find ODEC's projected wholesale power rates are reliable and should be used to determine the Cooperative's future purchased power costs. I further find the Cooperative's purchased power cost for the capped rate period is $5,591,085.00. This amount represents a reasonable estimate of the Cooperative's total purchased power cost for the capped rate period. I recommend the Commission use this amount as the basis for determining the Cooperative's generation cap in its functional separation case. If, as stated by the Staff, a different number is used, a subsidy may be created between the Cooperative's bundled rate customers and its unbundled rate customers. This result should be avoided, if at all possible.

In summary, I find the Staff's methodology for taking a "forward look" at the Cooperative's revenues, expenses, and changes in rate base for the period 2001 through 2007 satisfies the requirements placed on the Commission by § 56-582 A 3 of the Code of Virginia. Consequently, I recommend the Commission adopt the Staff's methodology, rate period, and billing determinants for use in this case. I further find the Cooperative's depreciation rates are reasonable and should be used in the Staff's methodology for determining the Cooperative's revenue requirement. The resulting revenue requirement for the Cooperative is $615,222.00. I find this revenue requirement is reasonable. The evidence indicates that the Cooperative's financial performance, as measured by TIER and DSC, is below the industry average when compared to its Virginia and national peers. In addition, the Cooperative's historic equity ratio has not compared favorably to its peers. This evidence points to a need for rate relief for the Cooperative. The $615,222.00 revenue requirement that I am recommending in this case provides that relief, and should ensure that the Cooperative remains on sound financial footing throughout the transition period. Attached to this Report as Appendix A are the revised Financial Status Statement that calculated the Cooperative's $615,222.00 revenue requirement and supporting revised depreciation schedules. Appendix B is a revised Financial Status Statement (In Nominal Dollars, Including Hearing Examiner's Rate

[12] ODEC's increased purchased power costs required to meet weather-related demand, and its own increased fuel costs, would flow through the fuel adjustment provision of the Cooperative's Wholesale Power Adjustment Clause. Under capped rates, the Cooperative may recover these costs from its customers. In reality, the Cooperative faces minimal exposure to increased wholesale power costs that could not be recovered from its customers during the period capped rates are in effect. (Ex. CH-5, Schedule 5A, at 17-19).

Increase) which shows the revenue requirement recommended in this case produces an average 2.25 TIER for the period these rates will be in effect.

FINDINGS AND RECOMMENDATIONS

Based on the evidence received in this case, and for the reasons set forth above, I find that:

(1) The methodology employed by the Staff in this case is reasonable and meets the requirements imposed on the Commission by § 56-582 A 3 of the Code of Virginia;

(2) The Staff's rate period and billing determinants are reasonable and should be used for setting the Cooperative's rates;

(3) Gross receipts taxes should be removed from the Cooperative's revenue requirement;

(4) The Cooperative's depreciation rates of 3.07% for its distribution equipment and 10% for its load management equipment are reasonable;

(5) The Cooperative's rate case expense, as adjusted by the Staff, is reasonable;

(6) The Cooperative's right-of-way expense, as adjusted by the Staff, is reasonable;

(7) The Cooperative's payroll expense, as adjusted by the Staff, is reasonable;

(8) The Staff's interest expense calculation is reasonable;

(9) The Cooperative's TIER should be set at 2.25;

(10) The Staff's cost of capital calculations are reasonable;

(11) The Cooperative's adjusted revenue requirement of $615,222.00 is reasonable;

(12) The Cooperative's Wholesale Power Cost Adjustment Clause should be amended to remove any reference to gross receipts taxes;

(13) The Cooperative's miscellaneous services charges, including its bad check charge, are reasonable;

(14) The Cooperative's change in its meter reading policy is reasonable;

(15) The Cooperative's change in its generation credit rider is reasonable;

(16) The issues related to the proper methodology for unbundling the Cooperative's rates and the resulting unbundled rates should be addressed in the Cooperative's functional separation case, Case No. PUE010002;

(17) The Cooperative's total purchased power cost for the capped rate period is $5,591,085; and

(18) The Cooperative's total purchased power cost as set in this case should be used as the basis for determining the generation cap in the Cooperative's functional separation case.

I therefore ***RECOMMEND*** the Commission enter an order that:

(1) ***ADOPTS*** the findings contained in this Report;

(2) ***APPROVES*** an increase in gross annual revenues for the Cooperative of $615,222.00;

(3) ***DIRECTS*** the Cooperative to allocate the approved rate increase to the retail classes in the same percentage as proposed by the Cooperative;

(4) ***APPROVES*** the Cooperative's tariff revisions as set forth herein;

(5) ***REQUIRES*** the Cooperative to file an affidavit certifying that all over-collections during the period interim rates were in effect have been refunded; and

(6) ***DISMISSES*** this case from the Commission's docket of active cases.

COMMENTS

The parties are advised that any comments (Section 12.1-31 of the Code of Virginia and Commission Rule 5 VAC 5-20-120) to this Report must be filed with the Clerk of the Commission in writing, in an original and fifteen (15) copies, within twenty-one (21) days from the date hereof. The mailing address to which any such filing must be sent is Document Control Center, P.O. Box 2118, Richmond, Virginia 23218. Any party filing such comments shall attach a certificate to the foot of such document certifying that copies have been mailed or delivered to all counsel of record and any such party not represented by counsel.

Respectfully submitted,

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Michael D. Thomas
Hearing Examiner